ALTERNATIVE
POST-INJECTION SITE CARE AND SITE CLOSURE PLAN
40 CFR 146.93(a)

PROJECT MINERVA

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

1.0 Introduction

This Post-Injection Site Care and Site Closure (PISC) plan describes the activities that Gulf Coast Sequestration will perform to meet the requirements of 40 CFR 146.93. Gulf Coast Sequestration will monitor ground water quality and track the position of the carbon dioxide plume and pressure front as they stabilize. Gulf Coast Sequestration may not cease post-injection monitoring until a demonstration of non-endangerment of underground sources of drinking water ("USDW") has been approved by the Underground Injection Control ("UIC") Program Director pursuant to 40 CFR 146.93(b)(3). Following approval for site closure, Gulf Coast Sequestration ("GCS") will plug all monitoring wells, restore the site to its original condition, and submit a site closure report and associated documentation.

1.1 Facility Information

Facility name: Project Minerva
Wells 1-4

Facility contact Benjamin Heard, Principal
2417 Shell Beach Drive, Lake Charles, Louisiana 70601
(713) 320.2497; bheard@gcscarbon.com

Well location: Calcasieu/Cameron Parish, Louisiana
Well No 1: [redacted]
Well No 2: [redacted]
Well No 3: [redacted]
Well No 4: [redacted]

2.0 Pre- and Post-Injection Pressure Differential [40 CFR 146.93(a)(2)(i)]

[redacted]

[redacted]

Table 2.1 Injection well initial pressures and pressures at return to pre-injection state, with dates

[redacted]

[redacted]

[redacted]

Figure 2.1 Injection well pressures at top perforations versus time

[redacted]

Table 2.2 Peak pressures for injection wells

[redacted]

[redacted]

Figure 2.2 Peak injection pressures (end of injection) per well, fracturing pressure, initial formation pressure and induced seismicity pressure limits

[redacted]

[redacted] Peak injection pressures (end of injection) per well, fracturing pressure, initial formation pressure and induced seismicity pressure limits [redacted]

2.1 Predicted Position of the CO_2 Plume and Associated Pressure Front at Site Closure [40 CFR 146.93(a)(2)(ii)]

[redacted]

[redacted]

Pressure plume in January 2050 – end of injection, 30 years after injection starts, layer K = 23

[redacted]

Figure 2.3 Pressure plume at the end of injection, 1 January 2050

[redacted]

Figure 2.4 Pressure plume 1 years after injection stops, 1 January 2051

[redacted]

Figure 2.5 AoR at the end of injection, 1 January 2050

[redacted]

Figure 2.6 AoR 1 year after injection stops, 1 January 2051

[redacted]

[redacted]

Figure 2.7 CO2 plume at the end of injection, 1 January 2050

[redacted]

Figure 2.8 CO2 plume 1 year after injection stops, 1 January 2051

[redacted]

[redacted]

Figure 2.9 Top-to-bottom azimuthal length of pressure, AoR and CO2 plumes versus time

[redacted]

Figure 2.10 Top-to-bottom speed of pressure, AoR and CO2 plumes

3.0 Post-Injection Monitoring Plan [40 CFR 146.93(b)(1)]

Modeling shows that at the Project Minerva site the pressure decreases rapidly following cessation of injection and that the rate of plume size increase begins to decrease sharply. By 10 years after the end of injection, the rate of plume size increase slows to rates which are not measurable (see Figure 2.9 and Figure 2.10 above).

Continuing azimuthal VSP and IZ pressure surveillance using the 6 in-zone wells and array of DAS receivers and sources at fixed locations deployed during the injection period during the post-injection phase will meet the requirements of 40 CFR 146.93(b)(1) (please see the Testing and Monitoring Plan). The rate of 1) in-zone pressure decrease and 2) edge of the CO_2 plume along selected azimuths will document the correctness of the model assumptions. After 30 years of monitoring, the site will be well understood, the model inputs and assumptions validated and the correctness of characterization in showing the absence of out-of-zone leakage pathways in the AoR validated. The rapid decrease in any new risks as the pressure magnitude and AoR decreases and plume migration decreases results in rapid decrease in risk of leakage of either CO_2 or brine.

The airborne conductivity survey will be repeated to determine if any changes in groundwater indicative of brine leakage have occurred. If any anomalies that are suggestive of leakage are detected, follow-up groundwater or surface analysis will be conducted following the site-specific procedures developed during year 2 and 3 of the injection phase.

Following repeat airborne survey, leakage monitoring is systematically demobilized. Groundwater monitoring will continue only at the water wells on the injection well pads (GW1 & 2) at 5-year intervals. Remote GW wells 3 - 5 will be P&A. Surface monitoring points will systematically be demobilized, leaving only representative stations of those that are showing trends in environmental changes.

The results of all post-injection phase testing and monitoring will be submitted annually, within 10-year PISC, as described under Section 3.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)] below.

A quality assurance and surveillance plan (QASP) for all testing and monitoring activities during the injection and post injection phases is provided in the Appendix to the Testing and Monitoring Plan.

3.1 Monitoring Above the Confining Zone

Table 3.1 presents the monitoring methods, locations, and frequencies for monitoring above the confining zone. Table 3.1 identifies the parameters to be monitored and the analytical methods GCS will employ.

Continued collection of data using the azimuthal VSP areas will confirm no changes in fluid composition are occurring above the Anahuac confining zone.

Groundwater monitoring will continue at GW wells 1 & 2.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
Surface water/soil/groundwater	Sample surface water and/or soil gas	As needed depending on interpreted possible leakage signal airborne survey	Assess environmental trends	One episode, to resolution
Chicot aquifer	Groundwater sampling	GW wells 1 & 2	At injection wells	Every 5 years
Miocene (Survey used for plume tracking as well)	VSP designed for plume tracking will also detect any fluid substitution in the Miocene	Fiber optic in injection well, azimuthal receiver arrays	Azimuthal coverage of the plumes	Annually
Near surface	Airborne survey	Site-wide	AOR	One time, first year after end injection

Table 3.1 Monitoring methods, locations, and frequencies for monitoring above the confining zone

3.2 Carbon Dioxide Plume and Pressure Front Tracking [40 CFR 146.93(a)(2)(iii)]

GCS will employ direct and indirect methods to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure. Table 3.2 presents the direct and indirect methods that GCS will use to monitor the CO_2 plume, including the activities, locations, and frequencies GCS will employ. No fluid sampling is planned for plume tracking. Rapid stabilization of plume precludes us of this method.

Table 3.3 presents the direct and indirect methods that GCS will use to monitor the pressure front, including the activities, locations, and frequencies GCS will employ.

Quality assurance procedures for seismic monitoring methods are presented in Section 4.3 of the QASP.

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
PLUME MONITORING				
Frio	VSP designed for plume tracking	Fiber optic in injection well, azimuthal receiver arrays	Azimuthal coverage of the plumes	To be calibrated to mass injection and validated with VSP vendor
Frio	Pulsed neutron or other saturation lo	Injection well 1-4	Plume center	5-year post-closure

Table 3.2 Post-injection phase plume monitoring

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency
DIRECT PRESSURE-FRONT MONITORING				
Frio	Downhole pressure monitoring	Injection well 1-4. IZ 1 and 2	Pressure is diffusive, history match whole plume	Continuous pressure, downloaded daily

Table 3.3 Post-injection phase pressure-front monitoring.

3.3 Schedule for Submitting Post-Injection Monitoring Results [40 CFR 146.93(a)(2)(iv)]

All post-injection site care monitoring data and monitoring results collected using the methods described above will be submitted to EPA in reports submitted every other year. The reports will contain information and data generated during the reporting period i.e., well-based monitoring data, sample analysis, and the results from updated site models.

4.0 Alternative Post-Injection Site Care Timeframe [40 CFR 146.93(c)]

GCS will conduct post-injection monitoring for 10 years following the cessation of injection operations. A justification for this alternative PISC timeframe is provided in Section 4.1 below. Regardless of the alternative PISC timeframe, monitoring and reporting as described in the sections above will continue until GCS demonstrates, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the project does not pose an endangerment to any USDWs, per the requirements at 40 CFR 146.93(b)(2) or (3).

4.1 Computational Modeling Results – 40 CFR 146.93(c)(1)(i)

[redacted]

[redacted]

Figure 4.1 Pressure plume in layer K = 23 in the model, 1 year after injection starts

[redacted]

Figure 4.2 Pressure plume in layer K = 23 in the model, 2 years after injection starts

[redacted]

Figure 4.3 Pressure plume in layer K = 23 in the model, 3 years after injection starts

[redacted]

Figure 4.4 Pressure plume in layer K = 23 in the model, 4 years after injection starts

[redacted]

Figure 4.5 Pressure plume in layer K = 23 in the model, 5 years after injection starts

[redacted]

Figure 4.6 Pressure plume in layer K = 23 in the model, 10 years after injection starts

[redacted]

Figure 4.7 Pressure plume in layer K = 23 in the model, 15 years after injection starts

[redacted]

Figure 4.8 Pressure plume in layer K = 23 in the model, 20 years after injection starts

[redacted]

Figure 4.9 Pressure plume in layer K = 23 in the model, 25 years after injection starts

[redacted]

Figure 4.10 Pressure plume in layer K = 23 in the model, 30 years after injection starts

Pressure plume in January 2051, 1 year after injection stops, layer K = 23

[redacted]

Figure 4.11 Pressure plume in layer K = 23 in the model, 1 years after injection stops

Pressure plume in January 2052, 2 years after injection stops, layer K = 23

[redacted]

Figure 4.12 Pressure plume in layer K = 23 in the model, 2 years after injection stops

Pressure plume in January 2055, 5 years after injection stops, layer K = 23

[redacted]

Figure 4.13 Pressure plume in layer K = 23 in the model, 5 years after injection stops

Pressure plume in January 2060, 10 years after injection stops, layer K = 23

[redacted]

Figure 4.14 Pressure plume in layer K = 23 in the model, 10 years after injection stops

[redacted]

Figure 4.15 Pressure plume in layer K = 23 in the model, 50 years after injection stops

[redacted]

Figure 4.16 Pressure plume in layer K = 23 in the model, 100 years after injection stops

[redacted]

Figure 4.17 CO_2 gas saturation plume in layer K = 23 in the model, 2 years after injection starts

[redacted]

Figure 4.18 CO_2 gas saturation plume in layer K = 23 in the model, 3 years after injection starts

[redacted]

Figure 4.19 CO_2 gas saturation plume in layer K = 23 in the model, 4 years after injection starts

[redacted]

Figure 4.20 CO_2 gas saturation plume in layer K = 23 in the model, 5 years after injection starts

[redacted]

Figure 4.21 CO_2 gas saturation plume in layer K = 23 in the model, 10 years after injection starts

[redacted]

Figure 4.22 CO_2 gas saturation plume in layer K = 23 in the model, 15 years after injection starts

[redacted]

Figure 4.23 CO_2 gas saturation plume in layer K = 23 in the model, 20 years after injection starts

[redacted]

Figure 4.24 CO_2 gas saturation plume in layer K = 23 in the model, 25 years after injection starts

[redacted]

Figure 4.25 CO_2 gas saturation plume in layer K = 23 in the model, 30 years after injection starts

[redacted]

Figure 4.26 CO_2 gas saturation plume in layer K = 23 in the model, 10 years after injection stops

[redacted]

Figure 4.27 CO_2 gas saturation plume in layer K = 23 in the model, 50 years after injection stops

[redacted]

Figure 4.28 CO_2 gas saturation plume in layer K = 23 in the model, 100 years after injection stops

4.1.1 Sensitivity Study

[redacted]

[redacted]

[redacted]

Figure 4.29 Vertical X-section of pressure plume along I = 181 in the model, end of injection

[redacted]

Figure 4.30 Vertical X-section of pressure plume along I = 181 in the model, 1 year after injection stops

[redacted]

Figure 4.31 Vertical X-section of pressure plume along I = 181 in the model, 2 years after injection stops

[redacted]

Figure 4.32 Vertical X-section of pressure plume along I = 181 in the model, 3 years after injection stops

[redacted]

Figure 4.33 Vertical X-section of pressure plume along I = 181 in the model, 10 years after injection stops

[redacted]

Figure 4.34 Vertical X-section of pressure plume along I = 181 in the model, 20 years after injection stops

[redacted]

Figure 4.35 Vertical X-section of pressure plume along I = 181 in the model, 30 years after injection stops

[redacted]

Figure 4.36 Vertical X-section of pressure plume along I = 181 in the model, 40 years after injection stops

[redacted]

Figure 4.37 Vertical X-section of pressure plume along I = 181 in the model, 50 years after injection stops

[redacted]

Figure 4.38 Vertical X-section of pressure plume along I = 181 in the model, 100 years after injection stops

[redacted]

[redacted]

Figure 4.39 Vertical distribution of [redacted] CO_2 plume mass, with time

[redacted]

Figure 4.40 Vertical distribution of [redacted] CO_2 plume mass, with time

[redacted]

[redacted]

[redacted]

Pressure plume in January 2150, 100 years after injection stops, layer K = 23

[redacted]

Figure 4.41 Extent of pressure plume 100 years after injection stops, layer K = 23 in model

[redacted]

Injection well pressures at top perforations (see table 1 for cell indices and depths)

[redacted]

Figure 4.42 well pressures at top perforations versus time

[redacted]

Boundary cell pressures against time, in layer K = 23 of the model

[redacted]

Figure 4.43 dP(psi) versus time in four boundary test cells

[redacted]

[redacted]

[redacted]

4.2 <u>Predicted Rate of Plume Migration – 40 CFR 146.93(c)(1)(iii)</u>

[redacted]

[redacted]

[redacted]

Figure 4.44 Top-to-bottom azimuthal length of pressure, AoR and CO_2 plumes versus time

Comparison of pressure and CO_2 plumes' speed of plumes (ft/year) versus time (ML Reveal model)

[redacted]

Figure 4.45 Top-to-bottom speed of pressure, AoR and CO_2 plumes

[redacted]

[redacted]

[redacted]

4.3 Site-Specific Trapping Processes – 40 CFR 146.93(c)(1)(iv)-(vi)

The following trapping mechanisms are considered:

1) Buoyancy trapping against the Anahuac Shale Formation;
2) Relative permeability hysteresis (capillary trapping);
3) Dissolution of gaseous phase CO_2 into the formation's aqueous phase;
4) Localized buoyancy trapping within 4-way closures, where they may exist.

Note: Trapping by mineralization was not modelled.

Please see Appendices 2 and 3 on relative permeability modelling and CO_2 dissolution – including bibliography.

Figure 4.46 shows the mass of CO_2 of trapped by different mechanisms against time. The results are based on the simulation model. Please see Appendices 2 and 3 for an explanation of the trapping mechanisms used and their associated data.

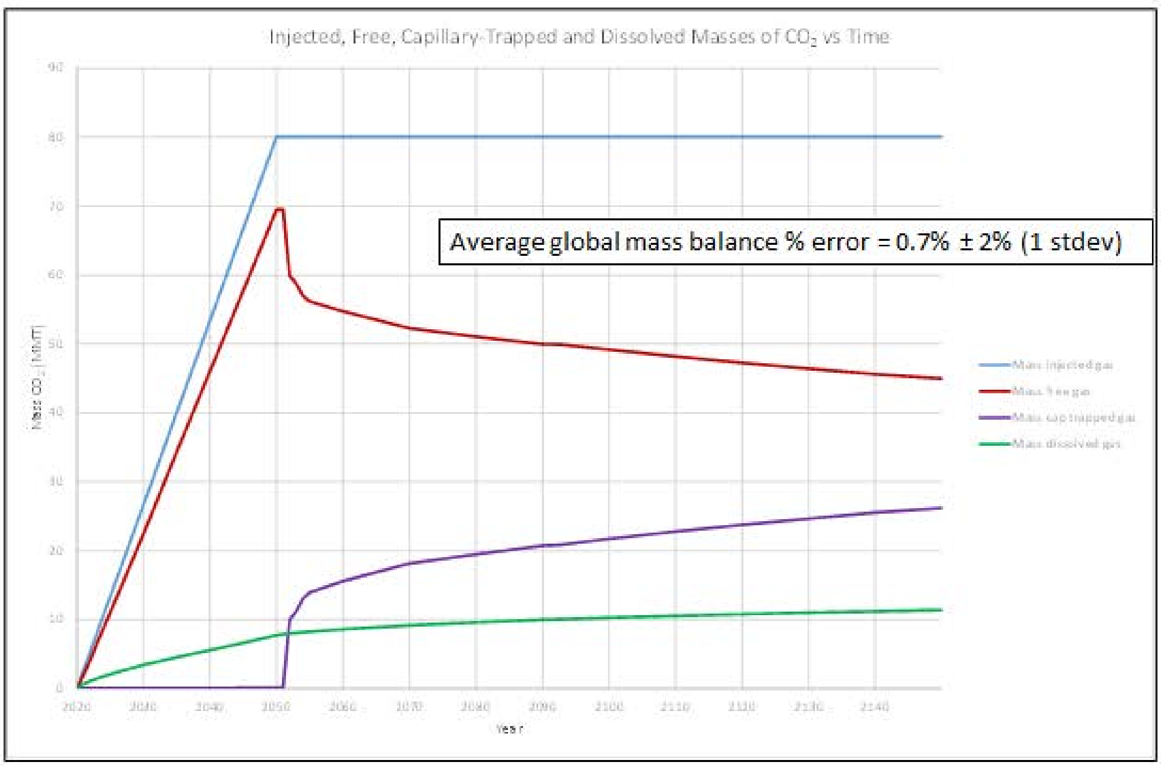

Figure 4.46 CO_2 mass balance and cumulative trapping

The trapping rates vary during the simulation. For example, capillary imbibition trapping does not occur significantly during the injection phase because it is a drainage process, the wetting phase is decreasing. When this stops, the wetting phase can move back in behind/underneath the CO_2 plume and it becomes an imbibition process (wetting phase increasing) and trapping of the non-wetting phase (CO_2) can occur through the snapping-off of some of the CO_2 ganglia within the pore spaces (Juanes, 2006). Some trapping can occur during injection, but it is not significant. Immediately following the cessation of injection, the rate of capillary trapping rises rapidly and then falls to a lower value. Immediately following the cessation of injection it rises rapidly and then falls to a lower value.

Trapping by dissolution occurs at a more constant rate, although it tends to decrease after injection stops, and then falls asymptotically.

No CO_2 mineralization was modelled.

4.4 Confining Zone Characterization – 40 CFR 146.93(c)(1)(vii)

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Table 4.6 Summary of all Frio-depth or deeper penetrations within the Area of Review

4.5.3 Planned Injection Well Construction

Injection wells will be constructed with mechanical integrity to meet-or-exceed the EPA UIC program Class VI guidance, with both internal and external components working together to ensure prevention of fluid movement into USDW. For internal integrity, concentric casing and tubing strings and wellheads of carbon steel and corrosion-resistant alloys will provide multiple barriers between the injected CO_2 and USDW. Tubing packers will employ nickel or corrosion-resistant alloy plus seals consisting of CO_2-resistant Teflon, nylon, or Buna-N rubber components. For external integrity, each casing string will be cemented from its bottom all the way to surface, using single or stage-cementing as required to emplace the cement column without causing fracture at any downhole formations. After placement of each cement column and suitable time allowed for hydration, logs will be run to confirm the competency of the cement barrier between the casing and the borehole wall.

4.5.4 Planned Testing and Monitoring of Barriers Between the Injection Zone and USDW

The ability of the internal barriers to protect USDW will be confirmed by initial and subsequent testing. An example of initial tests is a pressure test of the casing string in-place after cementing, to confirm no leakage through connections, and taking the baseline caliper survey inside the casing walls for comparison to subsequent surveys. Subsequent tests, besides the caliper survey mentioned, include continuous pressure monitoring of the annulus between the tubing string and the long string; this single annulus monitors the integrity of the tubing, the packer, and the long string.

4.5.5 Limited Risk to Well Integrity Through CO_2 Interaction with Wellbore Cement

The long-term degradation of cement by contact with CO_2 has been observed, but the external mechanical integrity of the injection well will be ensured by the continuous column of cement from base to surface. This length of cement will necessarily extend the full length of the confining layer, namely the Anahuac formation, several hundred feet thick. The CO_2 injectate, plus CO_2-contaminated formation brine in the Frio, will be confined at the Anahuac/Frio boundary. Cement around the casing string(s) through the confining Anahuac will not be subjected to contact with CO_2.

[redacted]

[redacted]

[redacted]

4.6 Location of USDWs – 40 CFR 146.93(c)(1)(x)

Additional information and figures describing the USDW in relation to Project Minerva may be found in the Hydrologic and Hydrogeologic Information section and the Class VI Permit Application Narrative document.

4.6.1 Lowermost Underground Source of Drinking Water

The primary regulatory focus of the USEPA injection well program is protection of human health and the environment, including protection of potential underground sources of drinking water (USDWs). The Underground Source of Drinking Water (USDW) is defined by the EPA as an aquifer which supplies any public water system and contains fewer than 10,000 mg/l total dissolved solids (TDS).

4.6.2 Regional Hydrogeology

The regional aquifer system is called the Gulf Coast Aquifer system and stretches from Texas, across Louisiana, Mississippi, and Alabama, and includes the western most portion of Florida. Miocene and younger formations contain usable quality water (<3,000 milligrams per liter (mg/L) TDS) and potentially usable quality water (<10,000 mg/L TDS), which is defined as base of lowermost USDW within this system. These aquifer systems regionally crop out in bands parallel to the coast and consists of units that dip and thicken towards the southeast. Baker (1979) describes four major hydrogeologic units that comprise the Gulf Coast Aquifer System in the Texas and Louisiana region. In ascending order, the four units are:

- Jasper aquifer;
- Burkeville confining system;
- Evangeline aquifer;
- Chicot aquifer.

The Burkeville confining system hydrologically separates the Evangeline aquifer from the underlying Jasper aquifer. However, the Chicot and Evangeline aquifers are thought to be hydrologically connected. A hydrogeologic stratigraphic column for southwestern Louisiana is contained in Figure 4.53. The primary focus of this assessment is on the Jasper, Evangeline, and Chicot aquifers in the southwestern portion of the state.

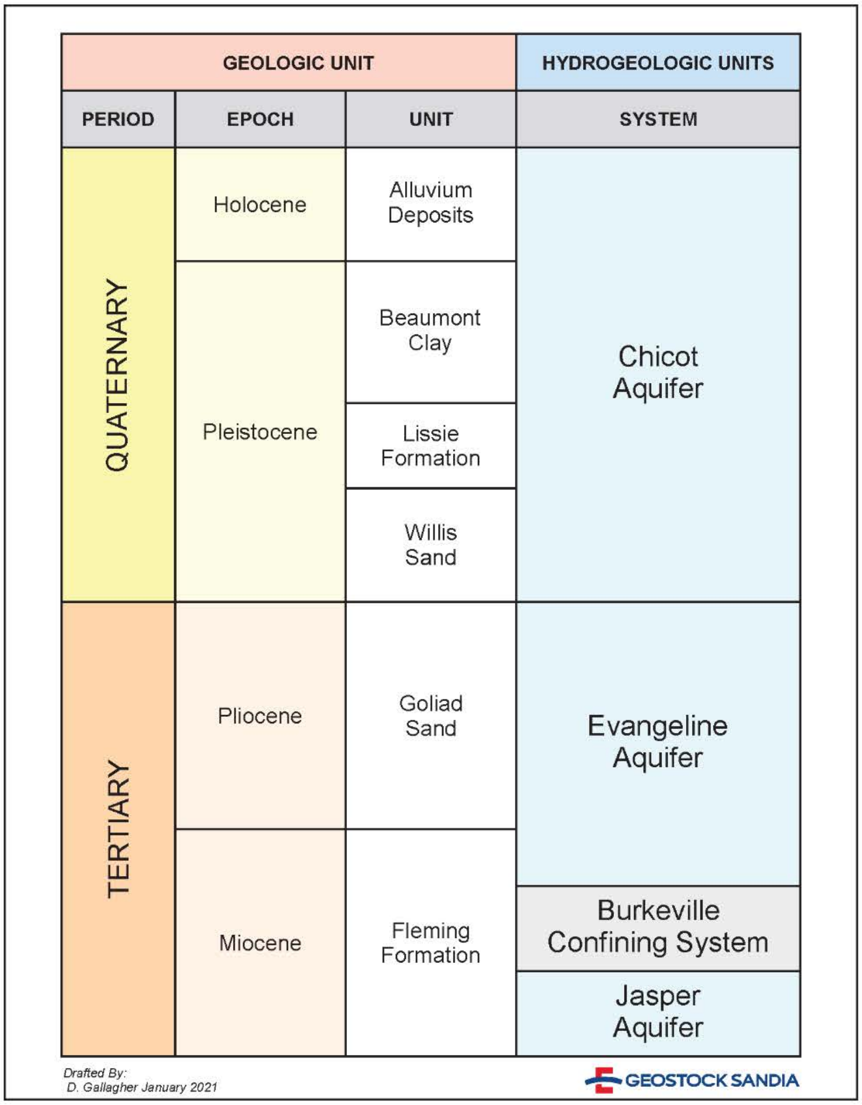

Figure 4.53 Regional hydrostratigraphic column for southeastern Texas and southwestern Louisiana.

The Jasper aquifer is not a major source for regional freshwater use in along the Gulf Coast, except in Beauregard, Rapides and Vernon Parishes. As the aquifer dips downwards towards the south (towards the coast), the groundwater increases in chlorides and is less commercially ideal to produce in comparison to the overlying Chicot and Evangeline aquifers. In Louisiana, the Jasper aquifer is primarily used as source only near its recharge areas. Its primary uses are for public water supply and industry with approximately 47.95 million gallons per day (Mgal/d).

Groundwater withdrawal from the Evangeline aquifer in Louisiana is almost half of that then from the Jasper aquifer. The Evangeline is used most heavily used in Evangeline Parish, as well as Allen, Avoyelles, and Beauregard Parishes for public supply and industry. It has also been used as a power supply source for the local areas. Approximately 28.56 Mgal/d were withdrawn from the aquifer in 2015.

The Chicot Aquifer yields the highest amount of groundwater for the State of Louisiana. It is the primary source of water for Calcasieu and Cameron Parishes. As the aquifer nears the coast, the lower units become saline and only the upper portions of the aquifer are used as a source of groundwater. Approximately 849.90 Mgal/d are produced from the entire aquifer. The largest contributor for withdrawal is for rice irrigation and aquaculture (crawfish harvesting), which are seasonal. As a result, during the off-peak irrigation season, the aquifer recharges, with the water level rebounding back to normal levels. The Chicot is also the largest supplier of public supply at 95.60 Mgal/day for the region and supports large cities such as Lake Charles in the area of interest.

4.6.3 Determination of the Lowermost Base of The USDW

The most accurate method for determining formation fluid properties is through the analysis of formation fluid samples. In the absence of formation fluid sample analyses, data from open-hole geophysical well logs can be used to calculate formation fluid salinity by determining the resistivity of the formation fluid (R_w) and converting that resistivity value to salinity value. The two primary methods to derive formation fluid resistivity from geophysical logs are the "Spontaneous Potential Method" and the "Resistivity Method". The "Spontaneous Potential Method" derives the formation fluid resistivity from the resistivity of the mud filtrate, and the magnitude of the deflection of the spontaneous potential response (SP) of the formation (the electrical potential produced by the interaction of the formation water, the drilling fluid, and the shale content of the formations). The "Resistivity Method" determines formation fluid resistivity from the resistivity of the formation (R_t) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987).

4.6.4 Spontaneous Potential Method

The spontaneous potential curve on an open-hole geophysical well log records the electrical potential (voltage) produced by the interaction of the connate formation water, conductive drilling fluid, and certain ion selective rocks (shales). Opposite shale beds, the spontaneous potential curve usually defines a straight line (called the shale baseline), while opposite permeable formations, the spontaneous potential curve shows excursions (deflections) away from the shale baseline. The deflection may be to the left (negative) or to the right (positive), depending primarily on the relative salinities of the formation water and the drilling mud filtrate. When formation salinities are greater than the drilling mud filtrate salinity, the deflection is to the left. For the reverse salinity contrast, the deflection is to the right. When salinities of the formation fluid and the drilling mud filtrate are similar, no spontaneous potential deflection opposite a permeable bed will occur.

The deflection of the spontaneous potential curve away from the shale baseline in a clean sand is related to the equivalent resistivities of the formation water (r_{we}) and the drilling mud filtrate (r_{mf}) by the following formula:

$$SP = -K \, Log\left(\frac{r_{mf}}{r_{we}}\right) \quad (1)$$

For NaCl solutions, K = 71 at 77°F and varies in direct proportion to temperature by the following relationship:

$$K = 61 + 0.133\,T° \quad (2)$$

From the above equations, by knowing the formation temperature, the resistivity of the mud filtrate, and the spontaneous potential deflection away from the shale baseline, the resistivity of the formation water can be determined (Figure 4.54). From the formation water resistivity and the formation temperature, the salinity of the formation water can be calculated (Figure 4.55).

4.6.5 Resitivity Method

The Resistivity Method determines formation fluid resistivity from the resistivity of the formation (R_t) and the formation resistivity factor (F), which is related to formation porosity and a cementation factor (Schlumberger, 1987). The resistivity of a formation (R_t in ohm-meters) is a function of: 1) resistivity of the formation water, 2) amount and type of fluid present, and 3) the pore structure geometry. The rock matrix generally has zero conductivity (infinitely high resistivity) except for some clay minerals, and therefore is not generally a factor in the resistivity log response. Induction geophysical logging determines resistivity or R_t by inducing electrical current into the formation and measuring conductivity (reciprocal of resistivity). The induction logging device investigates deeply into a formation and is focused to minimize the influences of borehole effects, surrounding formations, and invaded zone (Schlumberger, 1987). Therefore, the induction log measures the true resistivity of the formation (Schlumberger, 1987). The conductivity measured on the induction log is the most accurate resistivity measurement for resistivity under 2 ohm-meters.

Electrical conduction in sedimentary rocks almost always results from the transport of ions in the pore-filled formation water and is affected by the amount and type of fluid present and pore structure geometry (Schlumberger, 1988).

In general, high-porosity sediments with open, well-connected pores have lower resistivity, and low-porosity sediments with sinuous and constricted pore systems have higher resistivity. It has been established experimentally that the resistivity of a clean, water-bearing formation (*i.e.,* one containing no appreciable clay or hydrocarbons) is proportional to the resistivity of the saline formation water (Schlumberger, 1988). The constant of proportionality for this relationship is called the formation resistivity factor (F), where:

$$F = \frac{R_t}{R_w} \tag{3}$$

For a given porosity, the formation resistivity factor (F) remains nearly constant for all values of R_w below 1.0 ohm-meter. For fresher, more resistive waters, the value of F may decrease as R_w increases (Schlumberger, 1987). It has been found that for a given formation water, the greater the porosity of a formation, the lower the resistivity of the formation (R_t) and the lower the formation factor. Therefore, the formation factor is inversely related to the formation porosity. In 1942, G.E Archie proposed the following relationship (commonly known as Archie's Law) between the formation factor and porosity based on experimental data:

$$F = \frac{a}{\phi^m} \tag{4}$$

Where:

ϕ = porosity

a = an empirical constant

m = a cementation factor or exponent.

In sandstones, the cementation factor is assumed to be 2, but can vary from 1.2 to 2.2 (Stolper, 1994). In the shallower sandstones, as sorting, cementation, and compaction decrease, the cementation factor can also decrease (Stolper, 1994).

Experience over the years has shown that the following form of Archie's Law generally holds for sands in the Gulf Coast and is known as the Humble Relationship (Schlumberger, 1987):

$$F = \frac{0.81}{\phi^2} \tag{5}$$

Combining the equations for the Humble relationship and the definition of the formation factor, the resistivity of the formation water (r_{we}) is related to the formation resistivity (rt) by the following:

$$R_t = \frac{R_{we}\ x\ 0.81}{\phi^2} \tag{6}$$

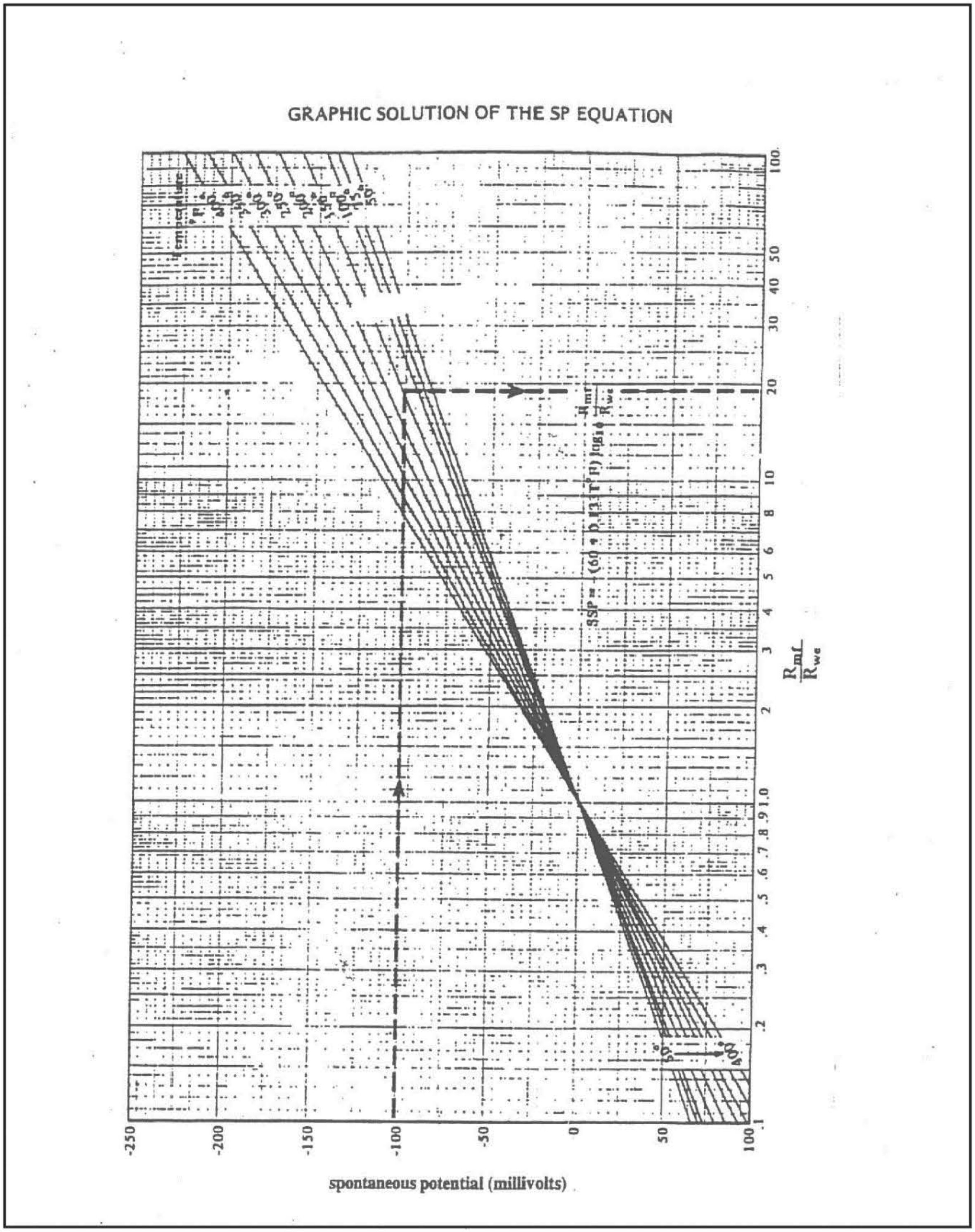

Figure 4.54 Graphic solution of the Spontaneous Potential Equation (Schlumberger, 1987)

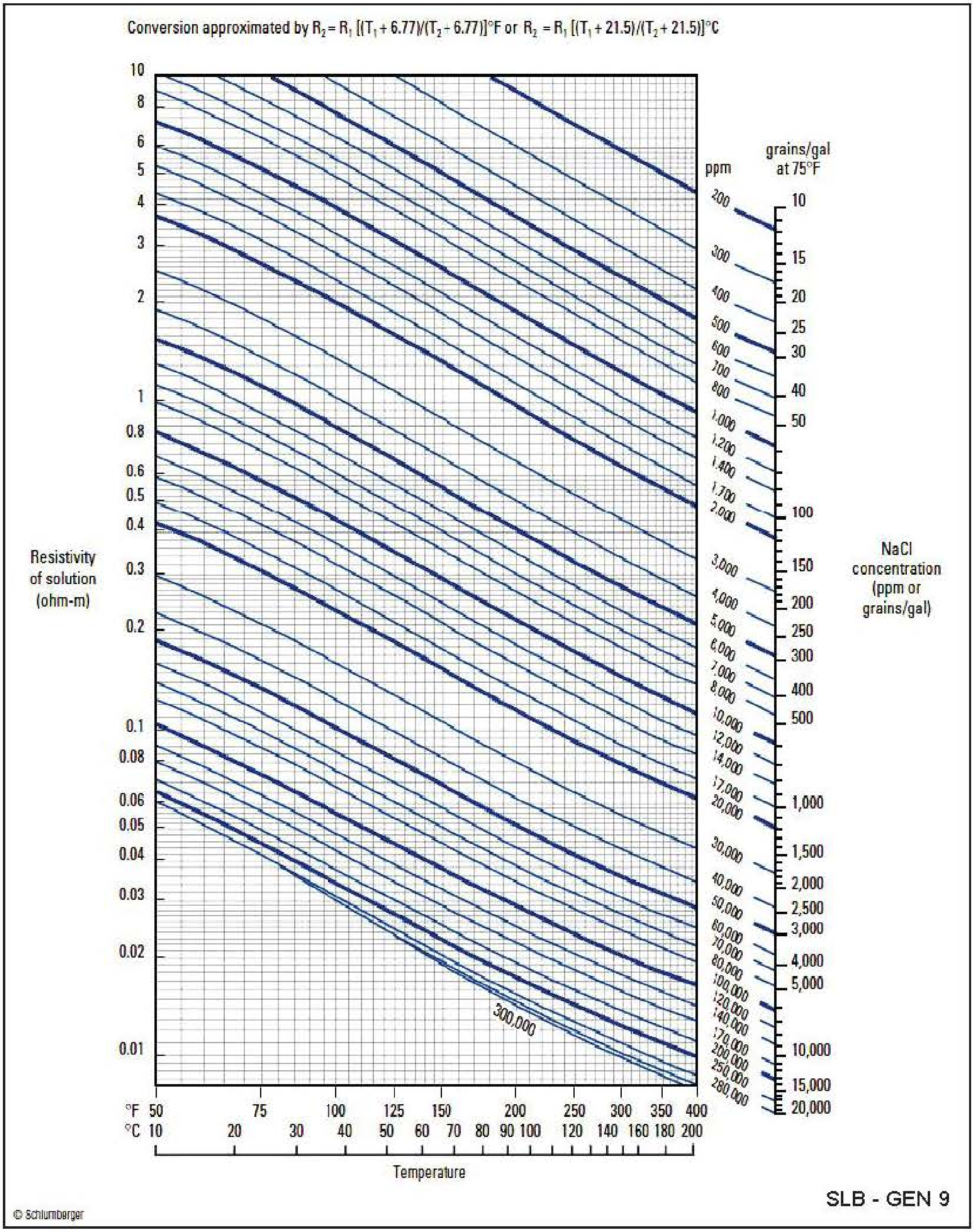

Figure 4.55 Resistivity nomograph for NaCl solutions (Schlumberger, 1979)

4.6.6 Methodology

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

4.6.7 Water Wells within the Area of Review

Water well data was gathered from the online database of the Louisiana Department of Natural Resources (LADNR), specifically the online GIS website SONRIS (*https://www.sonris.com/).* For the Texas portion of the search area, water well data was gathered from files maintained by the Texas Water Development Board (TWDB) (*https://www.twdb.texas.gov/).* The data was combined into a digital GIS format to merge the two data sets

A water well search was performed through SONRIS (Louisiana) and the TWDB (Texas). All water wells within the AOR are located within Louisiana. There are a total of 8 water wells located within the defined Area of Review ([redacted]). These wells extend from depths of 90 feet to 400 feet into the 200-Foot sand in the Chicot Aquifer. No wells are in the deeper aquifers of the Evangeline or Jasper. Five of these water wells are plugged and abandoned wells that supplied water from rigs, 1 is a current active supply for a rig, and 2 are currently used for domestic purposes.

4.6.8 Frio Penetrations with the Area of Review

A full integrity review of all wells within the Area of Review penetrating to Frio Formation depth and greater was carried out. The aim of the review was to confirm that all wells demonstrate adequate barriers between the Injection Zone and USDW. Nine wells were found to reach the Frio Formation; all are plugged and abandoned and possess one or more barriers which would prevent any communication with the UDSW. Full details of the review may be found in Section 4.5.1 [redacted].

4.6.9 Base of the Lowermost USDW

The base of the USDW has been projected across the Project Minerva area based upon 357 available wells logs. A base of the Lowermost USDW Map ([redacted] show the depth ranges from 850 feet ([redacted]) to 1,200 feet below mean sea level in the area (across the majority of the Area of Review around the planned injection wells).

The shallowest depth to the lowermost USDW lies across [redacted], where it is positioned within a sand package that directly overlies the top of the shallow salt. This sand is equivalent to the 700-Foot sand within the Chicot aquifer. The sand and the top of salt are separated by a thin (>10 feet) cap-rock clay bed. Saltwater encroachment occurs through vertical movement of hypersaline fluids in the area of the [redacted] through vertical leakage between the salt and the overlying strata. Sand units that directly overlay a salt bed are affected. In some instances, the conservative 2-ohm resistivity log cut off occurs within the middle of the sand package. This is an indication of a transition from freshwater to brackish/saltwater within the lower portion of the sand package. To maintain consistency, the base of the USDW was placed at the base of this sand, not at the transition point within the sand package.

[redacted], the base of the USDW deepens slightly to a range of 1,050 feet to 1,250 feet below mean sea level. The USDW is located at the base of a thick sand package that corresponds to the upper portion of the Evangeline aquifer. However, the Evangeline is not considered a "usable" aquifer with [redacted] and is not developed for use within the area. The top of salt is deeper at [redacted] and there is less influence via vertical leakage into the overlying aquifers due to a thicker cap-rock. However, as the strata dips towards the coast, saltwater encroachment into the deeper aquifers (Evangeline and Jasper) is evident in the southern portion of [redacted] due to pumping operations.

Within the AoR ([redacted]) the USDW varies between 1,080 feet to 1,130 feet depth (TVDSS). It encompasses the southern portion of the [redacted] The lowermost USDW is consistent with the base of the 700-Foot sand within this limited area. Note that the base of the USDW does NOT follow stratigraphic formation and that the units within the USDW are hydraulically connected. Thus, the USDW flows from the upper portion of the Evangeline into the base of the Chicot based upon the conservative 2-ohm resistivity cutoff.

4.6.10 Safety of the USDW

Overall, regional groundwater withdrawals within the Chicot aquifer have declined since 1985. Since the water levels are stabilized, withdrawal from the aquifers is not expected to influence either the safety of the injection site (non-endangerment of USDWs) or injection operations. The safety of the manmade conduits within the AoR and surrounding oil and gas fields (active and abandoned oil and gas wells), by casing, cement, or mud plugs, is demonstrated in Section 4.5.2 [redacted] and [redacted] to [redacted]. The target Frio Injection Interval at Project Minerva is separated by over [redacted]) from the shallow USDW's (<10,000 mg/L TDS) ([redacted]). Multiple additional saline "buffer aquifers" also exist between the top of the confining zone and base of the lowermost USDW, mitigating the vertical transmission of fluids upwards.

[redacted]

[redacted]

[redacted]

[redacted]

5.0 Non-Endangerment Demonstration Criteria

Prior to approval of the end of the post-injection phase, GCS will submit a demonstration of non-endangerment of USDWs to the UIC Program Director, per 40 CFR 146.93(b)(2) and (3).

GCS will issue a report to the UIC Program Director. This report will make a demonstration of USDW non-endangerment based on the evaluation of the Project Minerva site monitoring data used in conjunction with the project's computational model. The report will detail how the non-endangerment demonstration evaluation uses site-specific conditions to confirm and demonstrate non-endangerment. The report will include all relevant monitoring data and interpretations upon which the non-endangerment demonstration is based, model documentation and all supporting data, and any other information necessary for the UIC Program Director to review the analysis. The report will include the following sections:

5.1 Introduction and Overview

A summary of relevant background information will be provided, including the operational history of Project Minerva, the date of the non-endangerment demonstration relative to the post-injection period outlined in this PISC and Site Closure Plan, and a general overview of how monitoring and modeling results will be used together to support a demonstration of USDW non-endangerment.

5.2 Summary of Existing Monitoring Data

A summary of all previous monitoring data collected at Project Minerva, pursuant to the Testing and Monitoring Plan and this PISC and Site Closure Plan, including data collected during the injection and post-injection phases of the project, will be submitted to help demonstrate non-endangerment. Data submittals will be in a format acceptable to the UIC Program Director (40 CFR 146.91(e)), and will include a narrative explanation of monitoring activities, including the dates of all monitoring events, changes to the monitoring program over time, and an explanation of all monitoring infrastructure that has existed at the site. Data will be compared with baseline data collected during site characterization in satisfaction of 40 CFR 146.82(a)(6) and 146.87(d)(3).

Currently, there is no existing monitoring data.

5.3 Summary of Computational Modeling History

To date there has been no CO_2 injection or wells drilled for data collection. Hence, there is no data for history matching. A reservoir simulation model has been built in Reveal using a variety of data sources (see bibliography) to predict the development of the AoR, pressure and CO_2 plumes in time.

5.4 Evaluation of Reservoir Pressure

There will be regular pressure build-up tests (to determine reservoir pressure and injectivity) and continuous monitoring of downhole pressures and temperatures during injection, together with measurement of injection rates, tubing head pressures, temperatures and composition. These will be used as history matching data for future versions of the dynamic model. After calibration (history matching) the model will be used to update its predictions of the development of the AoR, pressure and CO_2 plumes.

5.5 Evaluation of Carbon Dioxide Plume

There will be regular VSP surveys, timing of such surveys based on mass injected and validated with VSP vendor, to determine the presence of CO_2 in the vicinity of the VSP line. These data measurements will be used as history matching data for future versions of the dynamic model. After calibration (history matching) the model will be used to update its predictions of the development of the AoR, pressure and CO_2 plumes

5.6 Evaluation of Emergencies or Other Events

The wells where this data is to be collected will be modelled in the dynamic simulation model and the calculated pressures, CO_2 saturations and other relevant data compared with the corresponding measured values to determine the accuracy and fidelity of the dynamic simulation model. Having calibrated the dynamic model, it can be used to predict the risk to that mobilized fluids pose a danger to USDWs.

6.0 Site Closure Plan

GCS will conduct site closure activities to meet the requirements of 40 CFR 146.93(e) as described below. GCS will submit a final Site Closure Plan and notify the permitting agency at least 120 days prior of its intent to close the site. Once the permitting agency has approved closure of the site, GCS will plug the monitoring wells and submit a site closure report to EPA. The activities, as described below, represent the planned activities based on information provided to EPA. The actual site closure plan may employ different methods and procedures. A final Site Closure Plan will be submitted to the UIC Program Director for approval with the notification of the intent to close the site.

6.1 Plugging Monitoring Wells

Methods to plug monitoring wells will follow the guidance for plugging Class VI injection wells. Sixty-day notice will be provided prior to plugging operations. Adjustments to the plugging plan will be incorporated to meet the Director's guidance.

It is unlikely or uncertain that a homogenous liquid will exist from the surface wellhead gauge down to the perforations (or screen in the case of a pure monitoring well). The homogenous liquid is required to accurately determine the downhole pressure at the perforations; a mixture of gas and super-critical phase CO_2 cannot yield accurate pressure calculations. Consequently, a wireline unit will deploy a tubing downhole pressure gauge with either surface read-out or recorded memory data, and the pressure at the perforations/screen will be measured directly.

After determining the downhole pressure at perforations, the equivalent density of fluid to balance this pressure will be calculated using the equation: Density = Pressure ÷ .052 ÷ TVD, where density is in pounds-per-gallon, pressure is psi, and TVD is feet.

A work fluid with the density calculated as above from the downhole pressure will be mixed from a freshwater base, with bentonite added for viscosity and barite added for weight. This fluid is robust at the expected temperatures and is compatible with common cement spacers and cements.

If the monitoring well does not have an existing tubing string installed, a work string likely consisting of 2-7/8" tubing will be run into the well using a workover rig. If the well has an existing tubing string with packer, the workover rig will make up a work joint to the existing tubing, pull tension to unseat the tubing hanger from the wellhead, and pull further tension to unseat the packer. With the tubing work string or the existing tubing/packer unseated, the work fluid will be slowly pumped down the tubing towards the perforations. If fluid returns do not arrive back at surface, it may be necessary to add lost circulation material (LCM) to the work fluid to plug the formation porosity at the perforations until fluid returns do arrive at surface. Pumping rate will be low so that undue friction pressures are not exerted on the formation open at the perforations; the volume to be pumped will be on the order of 200 bbls.

Note: this step should be considered as a bonus step, to be performed at the discretion of the owner/operator management and/or the Director. When the work fluid has been placed into the well and proven to balance formation pressure, and the tubing (either original or work string) have been pulled, a casing caliper log should be run on the long string. A baseline caliper log was taken when the casing was installed many years before, and possibly subsequent caliper logs have been run during the life of the well. A final caliper log would be run to determine the final condition of the long string's internal walls. It is likely that these walls have been continuously bathed by a non-corrosive fluid in the annulus between tubing and casing but obtaining the data and comparing to the years-old baseline log could provide bonus information to participants.

If the tubing existed in the wellbore with a packer attached, the tubing will be pulled and the packer removed; it is likely that any tubing joints connected to seating nipples will also be removed. The goal is to install in the wellbore a tubing work string from surface to plugged-back total depth (PBTD), which is usually the float collar of the casing long string. At this point, with no packer obstacle in the annulus, circulation will be repeated until it is confirmed that the work fluid has balanced downhole pressure at the perforations.

Circulation will be continued until fluid returns at surface appear to be clear from any debris, and pumping rates will be increased to determine the wellbore's tolerance for frictional pressures. Additions of LCM might be required to maintain circulation and this will be the time to learn the behavior of the wellbore. Determination of this tolerance and behavior will allow detail planning of the rates to be used during cementing operations.

It is proposed to set a series of balanced cement plugs inside the long string, beginning with a 500-ft cement plug across the perforations. Each cement plug will be designed by the cementing contractor to utilize cement types and additives suitable for each placement in the well; the first plug across the perforations will contain non-Portland cement components such as Pozzolan-Lime, Gypsum, Resin, or Latex to reduce or eliminate degradation by CO_2. No cement retainer or bridge plug is proposed at the top of this plug, as this adds mechanical complexity in a place where a simple solid cement seal is required.

After displacing the cement plug to the balanced depth, the tubing work string will be slowly pulled to a point at least 500 ft above the top of cement, and the tubing work string will be circulated (the long way, down the tubing and up the annulus) to clear any excess cement out of the well; reciprocate and rotate the tubing continuously during this circulation. Wait-on-cement for 24 hours, with periodic short circulations down the tubing to ensure it remains open-ended. After W.O.C. 24 hours (or such time recommended by cementing contractor for plug to achieve 100 Bc or 1000 psi compressive strength), run tubing work string slowly into well to tag the top of cement. Circulate through the work string during the final 90 ft (3 joints) to ensure that the tubing remains open-ended when it encounters cement. Tagging the cement top will determine the precise location of the cement compared to desired placement; additionally, set down 10,000 lbs of work string weight on top of the cement plug to prove its competency. The cross-sectional area of 2-7/8" tubing is approximately 2.7 in^2, and the force exerted on the cement top would be approximately 10,000 lbs ÷ 2.7 $in^2 \approx$ 3700 psi.

After successfully tagging the cement plug top and proving its competency, immediately pick up the tubing work string and circulate through it to clear any cement from the open end. Mix and pump via the balanced method another 500-ft cement plug similar to the first plug, placing it on top of the first plug. Repeat the process of pulling at least 500 ft above the calculated top of cement, circulating out any excess cement, W.O.C. while periodically circulating, and tagging the top of second plug and proving its competency.

Subsequent 500-ft high cement plugs will be planned for:

- the top of Anahuac, the confining formation above injection zone
- 250 ft above-and-below the depth of the surface casing shoe
- 250 ft above-and-below the base USDW
- at surface, from 510' to 10' below ground level.

As a conservative approach, each of the plugs will be tagged using the method described earlier. Tagging each plug will prove its location and competency, thus removing doubt about the suitability of the plugging process. It will be a time-consuming process due to the W.O.C. intervals, but successfully placed cement plugs will protect USDW.

Volume calculations will be based upon established oilfield methods, using measured pipe diameters. The series of casing caliper logs run over the life of the long string will provide the real-time inside diameter of that pipe after many years of service. The actual outside and inside diameters of the tubing work string can be measured on-site with hand calipers. An example calculation for volume of an annulus is: $(OD^2 - ID^2) \div 1029.4$ = volume in bbls per foot.

Prior to plugging, the internal competence of the long string will be tested by running a casing caliper log; this log will show remaining wall thickness. The external competence of the cement sheath around the long string will be tested by running a temperature or noise log, to determine if any fluid is moving in that cemented annulus.

During the lengthy injection period and possible monitoring period after injection, it is likely that surface equipment and infrastructure will have been upgraded, modified or replaced several times.

The plugged well would provide no usage to the owner/operator, so it is envisioned that all of the surface equipment will be removed piecemeal and the location pad and access road would be left in place.

6.2 Site Closure Report

A site closure report will be prepared and submitted within 90 days following site closure, documenting the following:

- Plugging of the verification and geophysical,
- Location of sealed injection well on a plat of survey that has been submitted to the local zoning authority,
- Notifications to state and local authorities as required at 40 CFR 146.93(f)(2),
- Records regarding the nature, composition, and volume of the injected CO_2, and
- Post-injection monitoring records.

GCS will record a notation to the property's deed on which the injection well was located that will indicate the following:

- That the property was used for carbon dioxide sequestration,
- The name of the local agency to which a plat of survey with injection well location was submitted,
- The volume of fluid injected,
- The formation into which the fluid was injected, and
- The period over which the injection occurred.

The site closure report will be submitted to the permitting agency and maintained by GCS for a period of 10 years following site closure. Additionally, the owner or operator will maintain the records collected during the post-injection period for a period of 10 years after which these records will be delivered to the UIC Program Director.

7.0 Quality Assurance and Surveillance Plan (QASP)

The Quality Assurance and Surveillance Plan is presented in the Appendix of the Testing and Monitoring Plan.

8.0 APPENDICES

8.1 APPENDIX 1 – Sensitivity Study on Reveal Simulation Model

Introduction

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

8.2 APPENDIX 2 – CO_2 dissolution in the Reveal Simulation Model

Please see Section 2.2.10 in the AoR and Corrective Action Plan report.

8.3 APPENDIX 3 – Saturation Functions in the Reveal Simulation Model

Please see Section 2.2.13 in the AoR and Corrective Action Plan report.

8.4 APPENDIX 4 – Area of Review Frio-depth Well Penetration Schematics

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

9.0 REFERENCES

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] www.osti.gov [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]